Appendix C

Calculation Procedures

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Hydrocarbons in Place

The oil and gas in place were calculated for each reservoir identified as oil or gas bearing in a field. The volume of oil or gas per acre foot of reservoir was calculated and then multiplied by the number of acres and the net pay thickness of the reservoir .

Initial Oil in Place

$$IOIP = \frac{7758 * \theta * (1 - S_w)}{B_o}$$

Initial Gas in Place

$$IGIP = \frac{7758 * \theta * (1 - S_w)}{B_g}$$

Where:
- IOIP = Initial oil in place (stock tank barrels / acre-foot)
- IGIP = Initial gas in place (thousand cubic feet / acre-foot)
- 7758 = Barrels per acre-foot
- θ = Porosity (fraction)
- S_w = Water saturation (fraction)
- B_o = Oil formation volume factor (reservoir barrels / stock tank barrel)
- B_g = Gas formation volume factor (reservoir barrels / thousand cubic feet)

Oil Volume

$$VO = \frac{IOIP * A * h}{1{,}000{,}000}$$

Gas volume

$$VG = \frac{IGIP * A * h}{1{,}000{,}000}$$

Where:
- VO = Oil volume (million barrels)
- VG = Gas volume (billion cubic feet)
- IOIP = Initial oil in place (stock tank barrels / acre-foot)
- IGIP = Initial gas in place (thousand cubic feet / acre-foot)
- A = Area (acres)
- h = Net pay (feet)

A recovery efficiency was applied to the volume of each reservoir to determine potential recoverable oil or gas. No consideration was given to economics of development.

Primary Oil Recovery

The fraction of the initial oil in place that would be produced by solution gas drive was calculated for each oil reservoir. The primary oil recovery factor for reservoirs with initial pressure above the bubble point pressure was calculated as the sum of the recoveries above and below the bubble point pressure. The initial oil in place for each reservoir was then multiplied by the recovery factor to determine the volume of oil recoverable under primary depletion.

Oil Recovery Above Bubble Point

The bubble point pressure and initial pressure were determined for each oil reservoir. If the initial pressure exceeded the bubble point pressure, an incremental recovery was calculated based on fluid expansion as the pressure dropped to the bubble point pressure. This recovery was added to the primary oil recovery that was calculated from the bubble point pressure to the abandonment pressure.

$$R_{aPb} = c_t \ (P_i - P_b)$$

Where:
- R_{aPb} = Fraction of IOIP recovered
- P_i = Initial reservoir pressure (psi)
- P_b = Bubble point pressure (psi)
- c_t = Total system compressibility (psi^{-1})

And:

$$c_t = c_w * S_w + c_o * S_o + c_r$$

Where:
- c_w = Water compressibility (psi^{-1})
- c_o = Oil compressibility (psi^{-1})
- c_r = Rock compressibility (psi^{-1})
- S_w = Water saturation (fraction)
- S_o = Oil saturation (fraction)

Oil Recovery Below the Bubble Point

Primary oil recovery of oil below the bubble point was calculated for each reservoir in units of barrels per acre foot; therefore, the area and net thickness of each reservoir were multiplied by the calculated recovery to determine the recovery in stock tank barrels from each reservoir identified as oil bearing. The statistical correlation for primary recovery was taken from a study by the American Petroleum Institute.[1]

$$R_{pri} = 3244 \ [\frac{\theta \ (1 - S_w)}{B_{ob}}]^{1.1611} * [\frac{k}{\mu_{ob}}]^{0.097}$$

$$* \ [S_w]^{0.3722} * [\frac{P_b}{P_a}]^{0.1741}$$

Where:
- R_{pri} = Primary oil recovery below bubble point (Barrels / acre-foot)
- θ = Porosity (fraction)
- S_w = Water saturation (fraction)
- B_{ob} = Oil formation volume factor at bubble point
- k = Permeability (darcys)
- μ_{ob} = Oil viscosity at bubble point (centipoise)
- P_b = Bubble point pressure (psi)
- P_a = Abandonment pressure (psi)

And:
- P_a = 0.1(psi / ft) * Depth to reservoir (feet)

Enhanced Oil Recovery

Many of the producing fields are being waterflooded to enhance oil recovery. Indications are that the waterfloods are inefficient by U.S. standards with high producing water-oil ratios and low incremental recovery. The extent of field development (well spacing), multiple reservoir fields, stratification of reservoirs, and lateral discontinuities would adversely effect the waterflood recovery efficiency. All of these conditions exist in the fields of the basin. Therefore, it is assumed that enhanced recovery will contribute an amount equal to the calculated primary oil recovery with the following limitations. Oil reservoirs in predominantly gas fields and the Bazhenov shale formation will not be waterflooded. Also, no reservoirs below the Jurassic section or with permeability less than 10 millidarcys will be subject to enhanced recovery processes such as waterflooding.

Associated-Dissolved Gas Recovery

Associated-dissolved gas recovery was calculated by multiplying the solution gas-oil ratio at the initial pressure by the recoverable oil volume. The initial pressures of the reservoirs were near the calculated bubble point pressures, and the reported initial gas-oil ratios confirmed the calculations of solution gas-oil ratios and bubble point pressures. No attempt was made to determine the recovery of the solution gas that was liberated from the remaining oil in place by pressure depletion. When the initial gas-oil ratio of a field was greater than the solution gas-oil ratio, the reported gas-oil ratio was used to calculate associated gas recovery. In several fields, an associated gas cap appears to affect the producing gas-oil ratio. Although the associated-dissolved gas volume for the basin is large, the amount of associated gas is minor compared to the amount of nonassociated gas in the basin.

Nonassociated Gas Recovery

Recoverable nonassociated gas was calculated as the difference between the initial gas in place and the remaining gas in place at an abandonment pressure. The abandonment pressure was calculated by multiplying an assumed abandonment gradient of 0.1 pounds per square inch per foot by the depth to the reservoir, which is consistent with the abandonment pressure used for calculating primary oil recovery.

Condensate Recovery

Significant condensate is produced in the transition area of the basin between the oil reservoirs in the central basin and the nonassociated gas reservoirs in the northern part of the basin. Condensate recovery was calculated using the yield in barrels of condensate per million cubic feet of gas produced as reported from gas reservoir tests. When data were not available, no recoverable condensate was assigned. Condensate volumes were added to oil volumes in the projections of future potential.

Future Projections

Future discoveries were projected using a modified logistics equation to fit the discovery history.[2] Total recovery from the basin was calculated by adding the undiscovered resources estimated by the USGS to the discovered reserves estimated in this analysis. Cumulative discovered reserves were calculated at each year in the future, and an iterative scheme was used to schedule annual production. Cumulative production was subtracted from the discovered reserves in each year to estimate remaining reserves. Production for the next year was then calculated based on a reserves-to-production ratio (R/P) that was previously determined. This production was added to the previous cumulative production and the process was repeated until the R/P equaled 1.0 (depletion).

The end-point of the projected R/P ratio was taken to be the last calculated discovery based on the logistics equation. For the oil case an end year of 2100 was used, and for gas; the final year was 2200. The historical R/P ratio for oil has been declining exponentially since 1980. Therefore an extrapolation of that trend was used to determine the future R/P ratio. The gas R/P ratio was also declining but a consistent trend had not been established. Therefore, an exponential decline from the current gas R/P to a final R/P of 1.0 in the year 2200 was used to approximate the productive capacity of the gas reservoirs (**Figures 1C and 2C**).

The logistic equation that was used in projecting cumulative discoveries is from the work of Hubbert,[3] with modifications by EIA.[4]

$$Q_D(t) = \frac{Q_{\max}}{1 + e^{\left[(B_1 S + (1 - S) B_4)(t - t_0 + B_2)\right]}}$$

Where:

$Q_D(t)$ = Cumulative discoveries at time t (remaining discovered reserves plus cumulative production).

Q_{max} = Ultimate recovery.

B_1 = A constant negative parameter that is slowly switched off.

S = The switching function which is equal to the quantity $e^{B_3(t - t_0)}$.

B_2 = A constant negative parameter that controls the timing of maximum theoretical production capability (the peak of the theoretical maximum production capability occurs approximately at the time when $t = t_0 - B_2$).

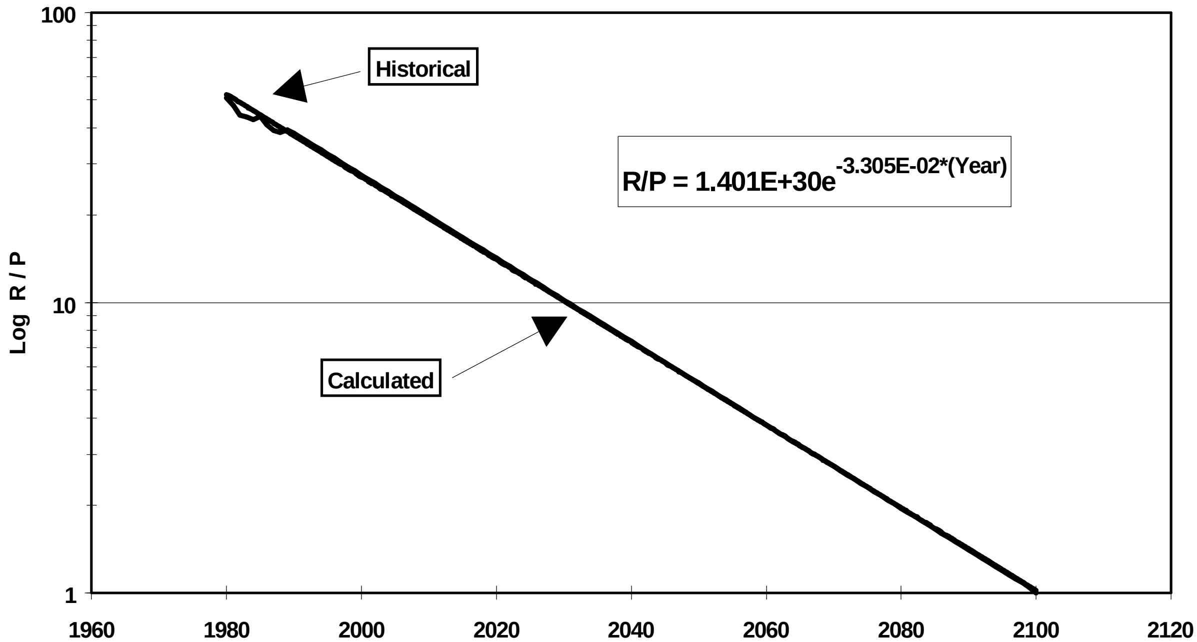
B_3 = A constant negative parameter that controls the rate of switch.

B_4 = The estimated decline rate from known deposits which, in turn, dictates the annual additions to proved reserves in the latter stages of development, also a negative parameter.

$(t-t_0)$ = The time after some reference period, t_0 .

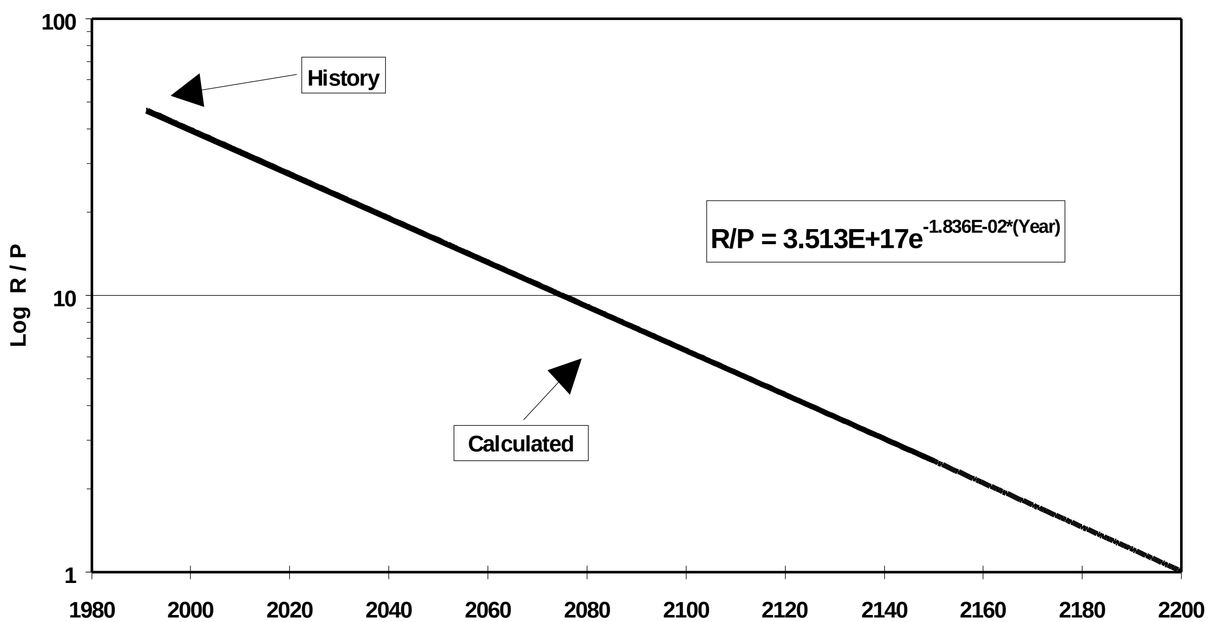
e = The base of the Naperian logarithms.

Figure 1C. Remaining Reserves / Annual Production Ratio (R / P) for Crude Oil Projection, West Siberian Basin



Source: Energy Information Administration, Office of Oil and Gas.

Figure 2C. Remining Reserves / Annual Production Ratio (R / P) for Gas Projection, West Siberian Basin



Source: Energy Information Administration, Office of Oil and Gas.

References

1. American Petroleum Institute, *A Statistical Study of Recovery Efficiency*, API BUL D14 (Washington DC, October, 1967).

2. SigmaPlot Scientific Graphing Software, *Transforms and Curve Fitting*, Revision SPW 1.0 (United States, July 1993).

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4. Energy information Administration, *Report on the Petroleum Resources of the Federal Republic of Nigeria*, DOE/IA - 0008 (Washington, DC, October 1979).